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Chapter 4 – Alternatives to the Proposed Project

There are several courses of action regarding the proposed project. The range of possibilities varies from taking no action, approving the entire project or portions of the project, or selecting some other alternative. This chapter explores these alternatives.

No Action

Taking no action on this application by denying the entire application (all three units) would result in no change in the number of power plants in the state.[39] WEPCO, and other electricity providers, would have the same sources of electricity available as they have currently. As power purchase agreements expire, with no new generation of its own to utilize, WEPCO would have to negotiate new power purchase agreements. Market rates for those purchases could vary from what they are now.

Taking no action on this application by not making a final PSC decision within the statutorily-mandated timeline would result in a CPCN automatically granted, for the project as proposed, to the applicants under Wis. Stat. § 196.491 (3)(g). The applicants would then have the option of constructing one or more of the three coal-fired units at any of the proposed sites. Without formal PSC approval, however, project financing might not be available. The entire project would still be subject to all DNR permitting requirements for construction and operation of the facilities.

Commission Energy Priorities

Wis. Stat. § 196.025 states "To the extent cost-effective, technically feasible and environmentally sound, the Commission shall implement the priorities under s. 1.12(4) in making all energy-related decisions." Wis. Stat. § 1.12(4) establishes the following priorities:

> (4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed:
>
> (a) Energy conservation and efficiency.

[39] This statement applies to the 2003-2011 time frame, the construction period for ERGS. It does not factor in the recent WEPCO-EPA agreement which would retire OOCP units 5 and 6.

(b) Noncombustible renewable resources.
(c) Combustible renewable energy resources.
(d) Nonrenewable combustible energy resources in the order listed:
1. Natural gas.
2. Oil or coal with a sulfur content of less than 1 percent.
3. All other carbon-based fuels.

The following sections in this chapter address these priorities, in the order listed above.

Load Reduction (Energy Efficiency) as an Alternative

Types of energy efficiency

Energy efficiency includes conservation, load management, and fuel switching. Energy conservation reduces the use of electric energy. Load management shifts energy use away from periods when demands are highest. Fuel switching replaces the use of electricity with the use of another fuel, such as natural gas. Load management shifts energy use away from periods when demands are highest.

The applicant states that the proposed generating facility is needed because the demand for electricity, including 18 percent reserves, will exceed available supply by 2,479 MW in 2011. Power outages would occur when demand for electricity exceeds supply. To correct such a situation, one can increase the supply or decrease the demand.

The generating facility proposed consists of two baseload SCPC coal units and one baseload IGCC coal unit. Fuel switching and general energy conservation contribute to addressing base loads, while load management is generally used to help meet peak loads.

Using energy efficiency to meet system electric needs can have both economic and environmental advantages over using supply resources such as power plants

Results of energy efficiency

Economic

The most significant economic advantage is that, if cost-effective, energy efficiency can reduce customers' electric bills. If the demand for electricity is reduced, less fuel needs to be bought and transported, and fewer power plants or power lines need to be built. This reduction in electric bills helps make Wisconsin businesses more competitive. By reducing the amount of money spent on energy in Wisconsin, energy efficiency can also improve the state's economy in general. This is because most of every energy dollar spent on coal, natural gas, and uranium, the fuels used by power plants to generate electricity, leaves Wisconsin and our economy.

Environmental

From an environmental perspective, energy efficiency is the best option for meeting energy needs. Conservation and some forms of fuel switching reduce air pollution, water use, coals and uranium mining, disposal of radioactive waste, production of greenhouse gases, and the depletion of non-renewable resources. All three forms of energy efficiency reduce the need for power plants and transmission lines, thereby reducing the negative impacts of these facilities. These impacts can include the use of valuable land, destruction of natural habitats, and aesthetic impacts.

There are some potential negative impacts associated with energy efficiency measures. An example of a negative impact from conservation is the need to dispose of spent fluorescent light bulbs. Switching fuels will still have impacts associated with the use of the alternate fuel. Load management, if not properly designed, can lead to discomfort or the inefficient disruption of industrial production. However, the negative effects of energy efficiency measures are negligible compared to the building and operation of power plants and power lines.

Regulation of energy efficiency

Traditionally, the Commission has relied upon electric and natural gas utilities to promote energy efficiency. Utility energy efficiency programs have largely been cost-effective and successful. It is estimated that from 1991 through 2001, Wisconsin utility programs reduced annual electric usage by about 4,300,000 MWh. Based on typical load factors of energy efficiency measures, these energy savings resulted in about 500 MW of peak demand reduction.

However, the regulatory approach to the promotion of energy efficiency has changed. New legislation passed in the fall of 1999 is having a significant impact on how energy efficiency services are delivered. Beginning in 2001, public utilities have less responsibility for delivering energy efficiency services. A substantial amount of utility ratepayers dollars that in the past funded utility-sponsored energy efficiency programs and services are now being transferred to the Department of Administration (DOA). In addition to this existing funding, new fees for energy efficiency are being collected from utilities. The DOA is responsible for the promotion of energy efficiency through administrators that were awarded contracts through competitive bids.

In addition to the DOA funding of energy efficiency discussed above, the utilities retained funds to be used for utility-administered, energy efficiency-related customer service conservation activities. Also, the utilities may provide, with Commission approval, energy efficiency services in addition to those provided by the DOA. Because the Commission approved retention of some energy efficiency funds, and can approve funds for additional energy efficiency services, the Commission continues to have some authority over utility energy efficiency services and accomplishments. The Commission also ensures that utility dollars are transferred over to the DOA, but has no other authority over DOA actions.

If the Commission finds, under Wis. Stat. §1.12(4) and 196.025, that energy efficiency or conservation can substitute cost-effectively for the proposed generating facility, the Commission's decision must ensure that the energy efficiency savings is implemented. For the Commission to choose energy efficiency over the proposed generating station, the Commission must find:

1. That enough energy efficiency exists to substitute for all or part of the energy demand that would be served by the proposed generating facility (if only part, then something else must provide the rest).
2. That energy efficiency would be cost-effective compared to the alternative facilities for which it would be substituting.
3. That the energy efficiency option is environmentally sound.

Applicant's analysis of energy efficiency as an alternative

The applicant states that it has constructed a portfolio of resources, including energy efficiency measures, to meet future needs. In order to include energy efficiency in its portfolio of resources, the applicant conducted an energy efficiency analysis to estimate the potential savings from energy efficiency programs.

The applicant's analysis first identified energy efficiency measures that can be used in its service territory. The applicant identified and collected technical data on about 100 residential measures. Using this technical data, technical potential was estimated. Technical potential is the load reduction that results when the most efficient measures are adopted by the entire eligible population.

A benefit-cost ratio was then calculated to estimate the economic potential. Economic potential is the load reduction that results when the most efficient measures are adopted when it is economical to do so from society's overall perspective. Measures found to be cost-effective were placed into a set of programs. The programs are sets of related measures that are bundled together and implemented by a utility or another party. When placing measures into the programs, the applicant assumed the measure could be implemented at an 85 percent penetration. This 85 percent market penetration is the applicant's estimate of market potential, or what can reasonably be assumed to be implemented by customers in response to utility, governmental, and marketplace products and services.

Market potential identified

The applicant's analysis identified about 340 MW of technically feasible energy efficiency by 2015. Of this 340 MW, the applicant identified a market potential of about 240 MW over the 2003-2015 timeframe. The applicant estimates that all but 10 MW of the 240 MW of market potential is already included in its forecast. This means that the applicant believes there is only 10 MW of additional energy efficiency that is available to substitute for a portion of the need for the proposed generating facility.

Additional analysis

The above discussion is based on the analysis the applicant provided in its CPCN applications in support of both the Port Washington Generating Station and ERGS. However, in the direct testimony of Karl McDermott and Val Jensen, the applicant submitted a new energy efficiency analysis. The applicant states that this new analysis was completed in response to issues raised in the Port Washington hearing regarding its energy efficiency analysis. The applicant further states that the new energy efficiency analysis in support of ERGS confirms the analysis previously provided by the applicant, although the achievable potential identified is not identical. The applicant's new analysis identifies an energy efficiency potential of between 57 and 146 MW in 2011 that is not already included in the applicant's forecast.

Staff's critique of WEPCO's analysis

PSC staff identified several shortcomings in the applicant's analysis provided in WEPCO's CPCN application. These shortcomings likely result in the applicants underestimating energy efficiency potential. First, the scope of the analysis was limited to the residential sector. In docket 6630-UR-109, the Commission determined that it is no longer appropriate for WEPCO to provide ratepayer-funded energy efficiency services to its Large Commercial and Industrial (C&I) customers, because its participation in the Large C&I energy efficiency market, using ratepayer dollars, would hinder the provision of energy efficiency services by non-utility entities. For this reason, the applicant did not include commercial and industrial customers in its analysis. The applicant also did not include Small C&I customers in its analysis. The applicant assumed the savings potential from these customers is small because sales to Small C&I customers are less than a third of residential sales.

In addition to not including C&I measures in its energy efficiency analysis, the applicant also included few fuel switching and load management measures. The few load management and fuel switching measures looked at by the applicant were rejected because the applicant deemed the measure not mature or not appropriate for Wisconsin. Although load management measures cannot address baseload needs, fuel switching measures can.

Another shortcoming of the applicant's analysis is that the level of energy efficiency savings already included in the forecast cannot be identified. The applicant states that because WEPCO's past energy efficiency efforts are reflected in the historical customer usage data used to develop the forecast for the proposed generating facility, it is reasonable to conclude that the forecast includes similar results. It is likely that some energy efficiency is included in the forecast. However, it is not possible to verify the applicant's contention that almost all of the 240 MW of market potential it identified is already in the forecast.

As a result of these shortcomings, it is likely that the Analysis provided by WEPCO in its CPCN application underestimates the availability of additional cost-effective energy efficiency. Commission staff has not completed its review of the new analysis provided by the applicant in its direct testimony.

Staff's analysis of energy efficiency potential

Commission staff also conducted an energy efficiency analysis. Staff's analysis compares the energy efficiency potential identified in the Commission-approved Statewide Technical and Economic Potential (STEP) Study, adjusted for market potential, to the level of energy efficiency estimated to be included in the forecast supporting the proposed generating facility. Because the proposed generating facility is a baseload plant, staff looked at the potential for both additional energy and demand savings. Commission staff's analysis estimates energy efficiency potential in the years 2007, 2009, and 2011, the proposed in-service dates of the ERGS units.

STEP Study

The STEP Study was a collaborative effort of the state utilities, interveners, and PSC staff that calculated the economic potential of energy efficiency over 20 years. This study was completed in 1994, and updated in 1995.

In the STEP Study "economic potential" was defined as the electric load reduction that results when the most efficient measures are adopted by the entire eligible population. The STEP Study provides an estimate of economic potential for both energy and demand. This was done for the 20-year period of 1994 through 2013. Conservation, load management, and fuel switching measures were all considered in developing the technical and economic potential estimates. The updated STEP Study identified a 20-year economic potential of 35 percent for energy and 29 percent for demand. STEP assumes that this potential will be achieved evenly over the 20-year period.

Market potential identified

The STEP Study reported demand and energy savings by the end of 20 years. Because it is not always cost-effective to replace existing equipment before the end of its useful life, replacement with more efficient technology was assumed to occur in a straight line during the 20 years. However, some technologies in the STEP report have useful lives less than 20 years. Given the uncertainty of the estimate of economic potential in 2007, 2009, and 2011, staff developed a scenario that assumed the full economic potential could be achieved in 15 years.

The STEP Study did not estimate market potential. Market potential is that portion of economic potential that is achievable knowing that some eligible customers will not install energy efficiency measures even when it is economic to do so. In order to compare results of the STEP Study to the level of energy efficiency included in the applicants' forecast, an adjustment for market potential must be made. There have been limited studies of market potential and the studies have been inconclusive. Given the uncertainty of market potential adjustments, Commission staff's analysis includes two scenarios, assuming market potential levels of 50 percent and 85 percent.

Commission staff's most aggressive scenario, which assumes the economic potential is achieved in 20 years and a market potential of 85 percent, identified more than an additional 600 MW of cost-effective savings by 2011, with more than 400 MW available by 2009 and about 200 MW available by 2007. A more conservative scenario, which assumes the economic potential being achieved in 15 years but only a market potential of 50 percent, identified 80 to 90 MW of additional cost-effective energy efficiency potential in 2009 and 2011. No additional cost-effective energy efficiency potential was identified in 2007 in this more conservative scenario.

Commission staff's analysis identified an additional potential of 3,650 GWh in 2007; 5,000 GWh in 2009; and 6,500 GWh in 2011 under its most aggressive scenario. Commission staff's more conservative scenario identified an additional potential of 2,050 Gwh in 2007; 3,000 Gwh in 2009; and 3,100 Gwh in 2011.

Shortcomings of Commission staff's analysis

Commission staff's analysis also has several shortcomings. Similar to the deficiencies in the applicant's analysis, these shortcomings likely underestimate the energy efficiency potential. First, staff used Advance Plan 8 (AP-8) estimates of naturally-occurring impacts in its estimate of the amount of energy efficiency already included in the applicant's forecast. Naturally-occurring impacts are those energy efficiency savings that occur without utility intervention in the energy efficiency market. The forecasting method used by the applicant in support of the proposed generation facility does not allow for the identification of naturally-occurring impacts. Although AP-8 provides the best estimate of naturally-occurring impacts available, it may no longer accurately reflect the naturally-occurring impacts in the applicant's forecast.

Second, the STEP Study was completed in 1994 and last updated in 1995. The energy efficiency market has changed considerably since the STEP Study was completed. Additional technologies are available, the cost of many technologies has decreased, and laws governing appliances and building shell efficiency have improved the market. Also, the avoided energy and demand costs upon which the STEP study was based are outdated. While it would have been better to rely on an updated study that reflects the existing energy efficiency market and today's avoided costs, one is not available.

In addition to being outdated, the STEP Study did not adequately address industrial energy efficiency potential. This significant weakness was stated in the study:

> "This analysis does not include some savings potential available in the industrial sector. This limitation is due to the complexity of estimating the potential for specific industrial processes and to the limited information in the Wisconsin Demand-Side Options Database regarding technology saturations… this limitation is likely to underestimate savings."[40]

Another weakness of the STEP study is the manner in which it addressed transmission and distribution. Although transmission and distribution losses are reflected in the estimate of savings potential, transmission and distribution avoided costs were not included in the avoided costs used to determine the cost-effectiveness of the energy efficiency measures.

Renewable Resources as an Alternative

In Wisconsin, the noncombustible renewable resources in use for electric generation are wind, solar and hydro. Combustible renewable resources include fuel cells fueled by hydrogen that is produced by a renewable resource and biomass energy derived from wood or plant residue, biological waste, crops grown for use as a resource, or landfill gas. The main renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy. At this time, solar power appears too costly to install on a utility scale and there is very little additional hydroelectric power potential available in Wisconsin.

Advantages of renewable resources include:

- Low or no fuel cost (except for some biomass).
- Short lead-times for planning and construction.
- Relatively small, modular plant sizes.
- Reduced environmental effects compared to fossil fuels.
- Non-depletable resource base.
- Potentially more job intensive.
- Favorable public opinion.
- Distributed generation potential.

General disadvantages include:

[40] Page E-3, Recalculation of Statewide Technical and Economic Potential

- Uneven geographic distribution.
- Intermittent nature of some resources.
- Lack of maturity or commercial availability of some technologies.
- Public concern for land use, biodiversity, birds, and aesthetics.
- Environmental issues with some types of biomass fuel supply.
- Relatively high capital cost for some technologies.

Wind

Design issues

Wind energy is converted to electricity when wind passes by blades designed like those of an airplane propeller mounted on a rotating shaft. As the wind moves the blades, the rotation of the shaft turns a generator which produces electricity. Three factors affect wind machine power: the length and design of the blades, the density of the air, and wind velocity. The power available to a wind turbine is directly proportional to air density, directly propoertional to area swept by the blades, and proportional to the cube of the wind velocity. [41] Blades are shaped and positioned to take advantage of different wind velocities so that, depending on design, one wind machine may produce power in a different range of wind velocities than another. Cold air is denser, which means it has more force, or ability to turn the blades. A wind machine in Wisconsin's cold, dense winter air can produce up to 20 percent more than the same machine with the same wind speed in hot summer air. Because output has an exponential relationship to the wind velocitry, the speed of the wind is critical for the cost-effective operation of wind machines. The higher the elevation at which a wind turbine is mounted, the more wind it will encounter. As the height of towers on which wind turbines are installed increases from the 65 meters that is typical today to the 80- and 100-meter towers of the newest machines, the average annual wind speed, and therefore, capacity factors will also increase.

Table 4-1 shows potential capacity and electrical generation based on the land area exhibiting each class of wind speed and assuming 12 MW per square mile.[42] Wind power imports from neighboring states with superior wind regimes are also not included because transmission constraints limit the availability of that power.

Table 4-1 Land-based Wind Power Potential in Wisconsin[43]

Class	Area (sq. miles)	Capacity (MW)	Capacity Factor	Estimated Output
Class 4 & 5	170	2,040	32.4	5,790,010 MWh
Class 3	3,330	39,960	20.0	70,009,920 MWh
Total Wind	3,500	42,000		75,799,930 MWh

[41] $P=\frac{1}{2}DAV^3$ (P=power produced; D=air density; A=swept area of the turbine blades; and V=the velocity of the wind in miles per hour).
[42] Based on data in Table 4-1, a 1,157 MW class 4 & 5 wind farm comprising 96 square miles would equal the output of one 500 MW coal plant with a 75 percent capacity factor.
[43] Windy land area from An Assessment of Windy Land Area and Wind Energy Potential in Contiguous United States, Battelle Pacific Northwest Laboratory, 1991.

Offshore Wind

Some of the areas with the best potential for new wind energy development are over large bodies of water such as Lake Michigan. In the past two years, the US Army Corps of Engineers (ACOE) has received permit applications for over 3,000 MW of wind capacity off the east coast of Massachusetts. A study done for the Long Island Power Authority in April of 2002 showed between 2,250 and 5,200 MW of wind-generated power available within six miles of Long Island's south shore. In northern Europe, 12 offshore wind projects with a total capacity of over 300 MW are in operation. According to a report by German consultant Klaus-Peter Lehman, some 70 offshore wind projects are now under development worldwide.

It is likely that within the time frame of the ERGS proposal, at least some of the wind resource in Lake Michigan would be developed. One developer has submitted an application to the ACOE for a project in Lake Michigan east of Chicago. Industry sources indicate that other developers are actively investigating sites elsewhere in the Great Lakes. Data gathered along the shoreline and from mid-lake buoys indicates that there may be significant potential wind capacity in Lake Michigan off the east coast of Wisconsin.

Development of offshore wind is also made more practical by larger turbines designed with offshore application in mind. Two examples are the General Electric 3.6 MW turbine on a 75-meter tower and the Vestas V90 on a 100-meter tower.

Staff's analysis of cost and potential

PSC staff used EGEAS modeling to compare alternatives to the proposed coal plants. EGEAS assumptions for wind include capital costs, operating and maintainance (O&M) costs, capacity costs, life of the federal product tax credit (PTC), and credit to reserve margin.

Overnight construction costs or capital costs for land-based wind power projects (in 2001 $) are assumed to be $1,029 per kW and O&M costs are estimated at $26 per kW-year. The cost of offshore wind is estimated to be 40 to 50 percent higher than land-based projects, or $1,500 per MW with an annual de-escalation rate of 4 percent with a variable O&M cost of $10 per MWh. These offshore O&M costs are based on industry experience in northern Europe. Winter ice conditions would tend to increase O&M costs for Lake Michigan; however, Lake Michigan has the advantage of fresh water and less turbulent winds than those in the North Sea. The capacity factor for offshore wind was set at 35 percent assuming an average wind speed of approximately 16 mph at 100 meters two miles offshore

The federal Production Tax Credit (PTC) for wind generation is an important factor when considering the relative cost of wind generation. The PTC, which has been renewed several times since going into effect on January 1, 1994, provides a tax credit of 1.5 cents per kWh plus an inflation adjustment for the first ten years of production from a qualifying wind power facility. The inflation adder is periodically adjusted by the IRS, so that in 2003 it is 1.8 cents per kWh. Current law applies only to wind and certain biomass facilities that come on line before December 31, 2003. However, there is reason to believe that the credit will be extended. Seven legislative proposals have been introduced in the U.S. Congress calling for extension of the credit for a period of anywhere from three years to indefinitely. Given the substantial, bipartisan support for extending the PTC, there is no reason to conclude that it will not be extended into the future.

Another important assumption in the Commission staff EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited toward WEPCO's reserve margin. This is conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent. On the other hand, WEPCO erroneously assumed no credit to reserve in its EGEAS runs.

Potential environmental and social effects

The environmental effects of wind energy are mostly positive, but there are some potentially negative impacts also. One of the major benefits of this technology is that it does not create air pollution. Power plants that burn coal, for example, emit sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), particulates, and heavy metals into the atmosphere. Gas-fired power plants emit NO_X, particulates and CO_2. Emissions from power plants contribute to acid rain which has been shown to damage lakes, streams, and forests. Power plant emissions also contribute to ozone formation which can affect human health and emissions of CO_2 have been linked to global warming.

Because wind-generated electricity does not use water, potential negative impacts such as thermal pollution of water bodies or water losses in surface and groundwater hydrologic systems are avoided. Wind energy also avoids impacts related to water use such as depletion of ground water supply and impacts to the supply and flow of surface waters. Wind energy does not create substantial solid waste (ash, etc.), so transportation, treatment, and storage of wastes are also avoided.

The risk of avian mortality is one of the major environmental concerns associated with wind energy. Bird collisions with turbine blades and towers have been reported in this country and in Europe. This issue is somewhat controversial and is the subject of increasing study. Impacts to birds and bats can be reduced with careful siting of facilities. Other issues often associated with wind energy include concerns about land use impacts, noise, aesthetics, and negative impacts to property values. Noise problems associated with wind turbine facilities are currently being studied in northeastern Wisconsin. Potential effects on property values are difficult to isolate. Market prices for rural and residential property normally change over time, subject to a variety of variables. Factors affecting property values include the general condition of the local and national economy, taxes, the reputation of the school system, and the availability and condition of infrastructure (i.e. roads, police and fire protection). It is impossible, at this time, to predict the impact to property values from the presence of wind turbines.

From a social and economic standpoint, wind power has several advantages. Wind energy generally requires a larger workforce than typical combustion turbine technologies, but smaller than typical coal-based facilities. Because wind power requires no fuel, the cost of wind generated electricity would not be affected by volatility in fuel prices.

As a stand-alone alternative, it is not likely that enough wind generation capacity is available to replace the entire 1,830 MW of the proposed ERGS facilities. However, wind power could be a significant component of an integrated resource alternative that could substitute for all or a portion of the ERGS. Wind power also has a higher ranking as a renewable resource than any carbon-based combustible fuel under the state's energy priorities law, Wis. Stat.§1.12(4). State law also requires the Commission to implement these priorities when making all energy-related decisions.

Biomass

Design and cost

Biomass energy is the energy derived from plant materials or residue and biological waste. Combustible gases from landfills or anaerobic digestion of waste material is referred to as biogas.

Solid biomass can be burned like coal to produce steam. It can also be gasified and burned like natural gas. Biomass can include waste wood from construction or demolition projects or from wood product manufacturing. It can also include crops or other plantings, such as switchgrass or willows. Waste wood is the most available source of biomass in Wisconsin today. Waste wood is currently burned in several generating plants in Wisconsin, including a few utility-owned plants, to produce steam for both electric energy and industrial processes. Table 4-2 shows the biomass fuel availability, in Wisconsin, based on an Oak Ridge National Laboratory study, Biomass Feedstock Availability in the United States: 1999 State Level Analysis.

Table 4-2 Annual dry tons per year (8,500 BTU/lb) available at $50 per ton delivered.

Biomass Source	Dry Tons (8,500 Btu/lb)	Capacity	Estimated Output
Forest residue	1,138,400		
Mill wastes	192,000		
Agricultural residue	5,179,618		
Energy crops	6,114,270		
Urban wastes	639,110		
Total Biomass	**13,263,398**	**3,028 MW**	**22,547,000 MWh**

At an 85 percent capacity factor, 3028 MW would yield 22,547,000 MWh of energy per year.

Several technologies that utilize solid biomass fuels are in use today. There are power plants that burn chipped wood alone and others that co-fire wood products with fossil fuels. Two additional technologies are at the pilot-plant stage. The first involves harvesting and burning the whole above-ground portion of trees. The second is the gasification of woody or herbaceous biomass.

Biogas is a form of biomass consisting of methane and other combustible gases that can be used in a conventional engine or gas turbine to turn an electric generator. Biogas can be generated from on-farm anaerobic digestion (AD), landfill gas collection, and wastewater treatment plants. Electric generation using on-farm digesters is the fastest growing use of biogas in Wisconsin. The primary application of AD is on dairy operations with 500 or more milk cows, but there is also potential at poultry and hog confinement facilities, as well as smaller dairies. In Table 4-3 the number of dairy animals in the state is used to estimate potential. This number may overestimate the amount of potential dairy AD, but it also could be low because it does not included poultry, hog, or food processing facilities. Landfill gas and wastewater treatment potentials shown in Table 4-3 are from AP7 ***Technical Support Document D21.***

Potential environmental and social effects

Air emissions from biomass combustion are generally less than those from coal or natural gas. Like coal or natural gas combustion, biomass combustion produces CO_2, an important greenhouse gas. Growing additional vegetation or crops to replace the burned plant material can recapture the CO_2 and avoid increasing the overall amount of CO_2 in the air. Biomass can also emit lower amounts of NO_x, produce less ash than coal, and release significantly less toxic material such as mercury.

Table 4-3 Biogas potential in Wisconsin

Biogas Source	Capacity	Estimated Output
Wastewater Treatment Plants	6.65 MW	52,000 MWh
Landfill Gas	27.0 MW	227,000 MWh
On-farm Anaerobic Digesters	250.0 MW*	1,994,100 MWh**

* Based on number of dairy animals in Wisconsin.
**Assuming a capacity factor just over 92 percent.

A closed methane digestion system on a farm or landfill would reduce the amount of methane lost to the atmosphere (methane is a "greenhouse gas"). In addition, the farm operators could still utilize the source manure for soil fertility, and the landfill operators could still operate the overall landfill as planned. Combustion of the methane as biogas on site at either the farm or the landfill would release emissions similar to those released by natural gas-fired combustion turbines or combined-cycle facilities but at a smaller scale.

Fuel supply can potentially have an impact on the environment. In AP 7, the Commission determined that potential fuel supplies for environmentally sound biomass-fired power plants should be used in the following priority order:[44]

1. Wood industry residues—e.g., lumber mill residues and sawdust, furniture manufacturing wastes, pallets, etc.
2. Urban, forest, or agricultural residues—residues resulting from logging cropping, or city tree trimming. Enough logging or cropping residue must be left on the ground to ensure stable soil conditions and appropriate plant nutrient cycling.
3. Woody or herbaceous energy crops—grown sustainably on cropland or in plantations and dedicated for conversion to electricity. Crops showing the most promise in Wisconsin include hybrid poplars, willows, and switch grass.
4. Natural woodlands—harvesting trees for fuel. This option is by far the least preferable and most complicated environmentally.

The environmental effects of obtaining these fuels vary. All would require truck or rail transportation. Storage emissions and other effects might be a concern. At this time, however, it is early enough in the development of biomass technologies in Wisconsin to investigate storage options and sustainable plantations using landscape-level ecological planning. While biomass technologies continue to progress, on-going research (adaptive resource management) can investigate questions about potential environmental impacts.

From a socioeconomic perspective, money paid for local renewable resources to produce electricity for the state could remain in the state and potentially benefit residents, instead of being paid to out-of-state entities for natural gas or other fossil fuels. This would be especially true for biomass-fuels and biogas generation if fuel crops and other fuel sources were grown on Wisconsin farmland.

[44] PSC docket 05-EP-7, Order dated December 22, 1995, page 21.

Cost assumptions for the biomass alternatives used in the EGEAS modeling are discussed later in this chapter.

Solar power

Design and cost

Photovoltaic (PV) cells convert sunlight directly into electricity. PV panels, consisting of multiple PV cells can be used in small groups on rooftops or as part of a substantial system for producing large amounts of electrical power. The amount of energy produced by a photovoltaic system depends upon the amount of sunlight available. The intensity of sunlight varies by season of the year, time of day, and the degree of cloudiness.

Currently, PV generated power is less expensive than conventional power technologies where the load is small or the area is too difficult to serve by electric utilities. The cost of producing electricity with photovoltaic systems is 30 to 40 cents per kWh; however, recent breakthroughs may reduce the cost of producing electricity with photovoltaic systems to 10 to 12 cents per kilowatt hour (kWh) or lower. This compares to 2.6 cents per kWh for existing coal plants and approximately 6 cents per kWh for natural gas generated power.

While further advances in solar technology are likely, some technologies are available today. As a result of private and government research, photovoltaic systems are becoming more efficient and affordable. Utilities also fund research in these same areas through membership in Electric Power Research Institute (EPRI). With continued improvement, it is likely that photovoltaic technologies will become increasingly cost competitive with conventional generation sources.

The cost of PV systems has been steadily falling as system components decrease in price and efficiency improvements are made in the manufacturing process. PV could be a cost-effective part of an integrated alternative to the second plant in the applicants' proposal.

Potential environmental and social effects

Compared to traditional methods of electric generation, photovoltaic systems have few environmental concerns. They include less hardware than most other electric generation technologies, and generally include no more toxic components than other technologies. The primary environmental impacts of large ground arrays are visual and can be solved by designing the arrays to blend with their surroundings. Since solar power does not involve combustion of fuels, it does not create air or water emissions and would not result in significant water losses or thermal impacts to surface water bodies. Banks of solar panels would replace or shade whatever vegetation occurred at their installation site, but sites without vegetation, such as roof tops, are also available.

Fuel cells and hydrogen

Design and cost

A fuel cell is an electrochemical device that generates electricity by combining hydrogen from a hydrogen-rich fuel (methane, methanol, propane, or biomass) with oxygen from the air to produce electricity, heat, and water. All fuel cells consist of an anode, a cathode and an electrolyte; much like a battery, except that the reactant fuel is continuously fed to the cell. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electrical current. Each individual fuel cell produces less than one volt of potential, so cells must be stacked to obtain the desired voltage.

Typically, fuel cell capacities range from 2 kilowatt (kW) to 2 MW, and fuel cells have electrical efficiencies that range from 45 to 65 percent. With heat recovery, the efficiency can be as high as 85 percent. Four types of fuel cells are receiving the most attention today. They are the phosphoric acid fuel cell, molten carbonate fuel cell, solid oxide fuel cell, and proton exchange membrane fuel cell.

Hydrogen, the required fuel source for fuel cells, can be produced from water using electrolysis, with the necessary electricity generated using renewable energy. The National Aeronautic and Space Administration is currently working on a "regenerative fuel cell" that would be a closed-loop form of power generation. In the regenerative fuel cell, water is separated into hydrogen and oxygen by a solar-powered electrolyser and fed into the fuel cell to produce electricity and water. The water is then re-circulated to the electrolyser to complete the cycle. However, because this method is relatively expensive, most current fuel cell systems use some form of hydrocarbon fuel as their hydrogen source.

Some source compounds will have fewer and smaller amounts of by-products. The following is a list of hydrogen sources ranked in order of increasing by-products:

- Water
- Methane
- Propane and natural gas
- Gasoline
- Fuel oil
- Gasified coal

Even though they might depend on fossil fuels, fuel cells, because of higher efficiencies and lower fuel oxidation temperatures, emit less carbon dioxide (CO_2) and nitrogen oxides (NO_x) per kilowatt hour (kWh) of power generated than gas turbines or internal combustion engines. The overall air emissions are lower for fuel cells, but the difference is not significant for sulfur dioxide (SO_2) or particulates. If fuel re-forming is done on site, heat produced from the fuel cell process powers the reformer. If the re-forming is done off site, the resultant pollutants would be produced off site, and there would be additional pollutants from transporting the hydrogen to the fuel cell site. Unlike gas-fired combustion turbines and combined-cycle units, noise and vibrations associated with fuel cells are practically non-existent because the fuel cell itself has no moving parts.

As fuel cells decrease in price as a result of large R&D commitments on the part of both government and industry they could become a cost-competitive part of an integrated alternative to a second or third ERGS unit.

Applicant's analysis of renewables as an alternative

WEPCO provided cost comparisons and other parameters for renewable energy sources such as biomass, solar photovoltaic, and wind energy. WEPCO used the Electric Generation Expansion Analysis System (EGEAS) model to analyze additional alternatives to the ERGS. EGEAS is a modular production-costing, generation-expansion software tool that is used to find least-cost generation system plans by comparing all combinations of multiple generation options to meet forecasted system load. EGEAS inputs include forecasted energy and demand, the characteristics of existing and possible new generation units, fuel price forecasts, known or expected energy purchase or sales, desired reserve margin, and the forecasted cost of emission allowances.

WEPCO has signed a Memorandum of Understanding with the American Wind Energy Association, Citizens Utility Board (CUB), Customers First! Coalition, Midwest Renewable Energy Association, RENEW Wisconsin, Sixteenth Street Community Health Center, and Wisconsin Energy Conservation Corporation for a ten-year collaborative process with the stated objective of achieving, by the end of 2011, a target of five percent of all electric energy delivered to WEPCO customers coming from renewable resources. WEPCO has also proposed committing $6 million annually to accomplish this goal. In testimony for the Port Washington phase of PTF, the company stated that its commitment to renewable energy development is conditional upon approval of the entire PTF project, including the ERGS facilities.

Staff's analysis of renewables potential

Commission staff also used EGEAS modeling to compare alternatives to the proposed coal plants. The EGEAS runs incorporate the federal Production Tax Credit (PTC) for wind generation. The PTC, which has been renewed several times since going into effect on January 1, 1994, provides for a tax credit of 1.5 cents per kWh plus an inflation adjustment for the first ten years of production from a qualifying wind power facility. The inflation adder is periodically adjusted by the IRS, so that in 2003 it is 1.8 cents per kWh. Current law applies only to wind and certain biomass facilities that come on line before December 31, 2003. However, there is reason to believe that the credit will be extended. Seven legislative proposals have been introduced in the U.S. Congress calling for extension of the credit for a period of anywhere from three years to indefinitely. Given the overwhelming, bipartisan support for extending the PTC, there is no reason to conclude that it will not be extended into the future.

Another important assumption in the EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited toward WEPCO's reserve margin. This is somewhat conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent.

Natural Gas-Fired Combined-Cycle and/or Simple-Cycle as an Alternative

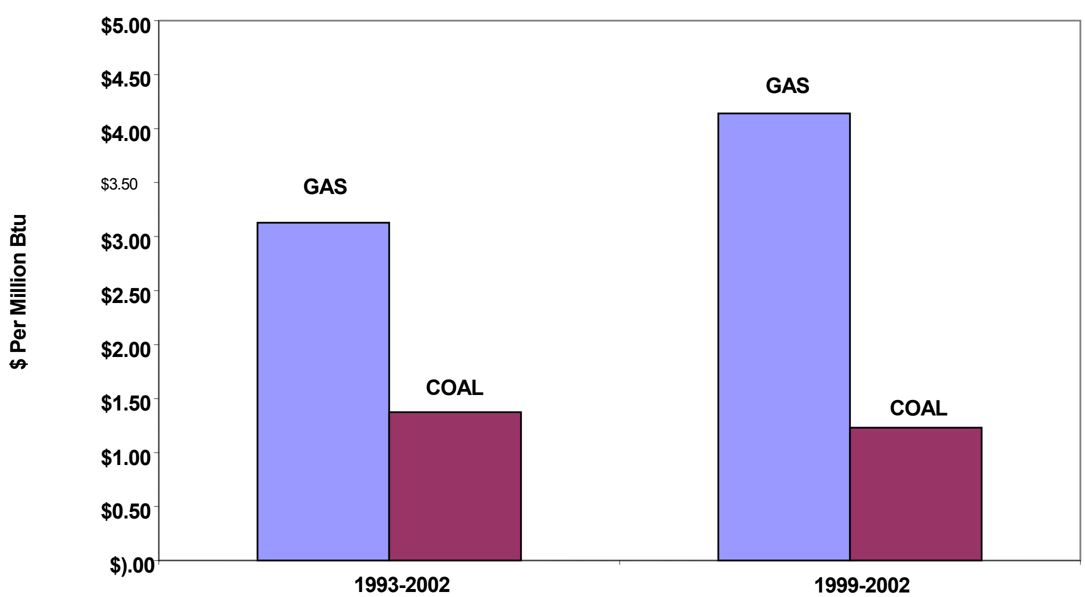
Fuel cost comparisons

An analysis of whether natural gas-fired generation should be built instead of coal generation should include, among other analyses, a comparison of natural gas prices and coal prices. Natural gas is a high-energy-content, premium fuel. These desirable features are offset, however, by the high cost of natural gas on a Btu-adjusted basis, and also by the extreme volatility of natural gas prices.

The average real cost of natural gas sold to electric generators over the past 10 years (1993-2002) has been \$3.13 per million Btu (2002 dollars).[45] In contrast, the average real cost of coal over the same period has been \$1.37 per million Btu. Natural gas costs have, on average, been 128 percent higher than coal costs over this period. If more recent data are examined, the difference in cost is even more dramatic. Over the past three years (2000-2002) the average real cost of gas was \$4.14 per million Btu, whereas the real price of coal averaged \$1.23 per million Btu over this period. Thus, in recent times, natural gas prices were 237 percent higher than coal prices. These cost comparisons are shown in Figure 4-1.

Making accurate predictions of future natural gas prices is difficult due to the extreme volatility of the data series. The standard deviation[46] of the annual natural gas price changes over the past 10 years is 24 percent. This contrasts with the standard deviation of annual changes in coal prices of only 2 percent.

Figure 4-1 Average cost of fuels used for electric generation over various time periods



45 Price data is from the US Energy Information Administration. Prices were converted to constant dollars via use of the GDP price deflator.
46 The standard deviation is a statistical measure of the dispersion of a data series.

The wide dispersion of natural gas prices in turn leads to very wide statistical prediction intervals for the price of natural gas over time. This can be demonstrated via the following random-walk model[47] of real natural gas prices:

$$\log \text{Gas Price}_{t+1} = \log \text{Gas Price}_t + \varepsilon_{t+1}$$

where

log = natural logarithm
Gas Price_t = real gas price in time period t
Gas Price_t+1 = real gas price in time period t+1
ε_t+1 = log-normally distributed random disturbance in time period t+1

Statistical forecasts can be generated from this model. For example, if this model reasonably represents the behavior of real natural gas prices, then one could be 90 percent sure that the 2003 average annual real gas price forecast would range between $2.48 to $4.91 per million Btu. This range is quite large.

The width of the prediction interval increases as the forecast period moves further into the future. For example, the 90 percent prediction interval for the year 2007 is $1.93 to $6.32 per million Btu. The 90 percent prediction interval for the year 2012 is $1.18 to $10.32 per million Btu.

This analysis indicates that real natural gas prices are essentially unpredictable for planning purposes. The real cost of natural gas for generation over the next five years might be below $3.20 per million Btu, but it also could just as easily be above $5.50 per million Btu. There is a smaller chance that it might decline to below $2.00 per million Btu, but there is also a small chance that it could increase to above $8.00 per million Btu. These types of prediction intervals do not provide much useful guidance as to the likely cost of natural gas over the long term.

Statistical forecasts of real coal prices have much tighter prediction intervals. For example, the 90 percent confidence forecast interval for real coal prices for the year 2012 is $0.58 to $2.55 per million Btu. This contrasts with the real natural gas price forecast interval of $1.18 to $10.32 per million Btu for the same time period. The contrast in predictability for natural gas prices versus coal prices is shown in Figure 4-2.

The volatility of the natural gas data makes it very difficult to draw firm quantitative conclusions about future natural gas prices. One can, however, draw important qualitative conclusions from this analysis. Those conclusions are:

- It is reasonable to assume as a base case that natural gas will continue to be significantly more expensive than coal over the generation planning horizon.
- The risk of incurring very high fuel prices is much greater for natural gas than it is for coal.

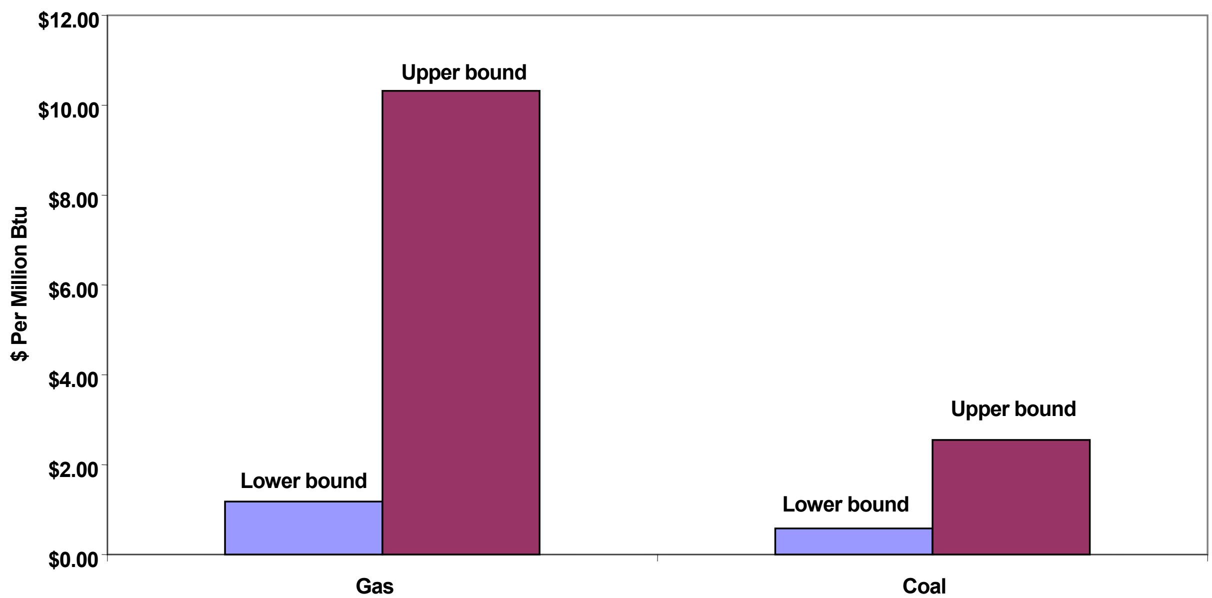
Staff's analysis of natural gas potential

Commission staff included the potential for some generic natural gas-fired combustion turbines in its EGEAS modeling runs and it also modeled and analyzed a proposal for a natural gas-fired combined-cycle plant that was filed at the PSC by Calpine Corporation as an alternative proposal to the ERGS. This

[47] The random-walk model assumes that the best estimate of today's price is yesterday's price.

proposal is described in more detail and compared with the proposed ERGS facilities in the following sections.

Figure 4-2 Statistical prediction intervals (90 percent confidence) for fuels used for electric generation for the year 2012



Alternative Proposals from Independent Power Producers

Applicant's treatment of IPP alternatives

As an alternative to all or part of the ERGS, WEPCO could rely on electric generation from an independent power producer (IPP) not affiliated with the utility or any of its affiliates. Such an alternative would require an IPP to construct a wholesale merchant power plant or sell electricity from a plant that is already operating but which has not contracted for all of its electrical output.

In its cost analysis filed in the CPCN application, WEPCO modeled purchases from generic or hypothetical power plants. WEPCO did not solicit power plant proposals or bids from IPPs that would directly compete with the ERGS coal facilities. This means that the costs under the proposed facility lease have not faced market discipline per se and are proxy costs that WEPCO believes are reasonable based on the company's insight of the marketplace.

In some instances, such an approach can be reasonable, especially if a formal bidding-type process to gather such market information would be expensive, untimely, or resource intensive. On the other hand, the use of competitive forces does foster cost discipline that ultimately benefits ratepayers. The fact that WEPCO did not issue an RFP for the capacity of ERGS may be an important issue at the hearing. In addition, the evaluation process itself may be an issue at hearing.

Calpine's proposal

On its own volition and as an alternative to the ERGS project, Calpine Corporation (Calpine) submitted a proposal to the PSC on February 19, 2003 that would develop a nominal 523 MW combined-cycle natural-gas-fired power plant in the town of Fond Du Lac, Fond du Lac County, with similar additional 500 MW units located elsewhere in the state. Calpine's February 2003 proposal which includes the full output of the Fond du Lac Energy project would be in lieu of the coal plants proposed for ERGS. On May 5, 2003 the Commission issued its Order approving Calpine's CPCN application for the Fond du Lac Energy project (docket 9343-CE-100). In addition, on June 20, 2003 Calpine updated its February 2003 proposal by including 260 MW of combined-cycle natural gas-fired capacity from Calpine's recent purchase of the Fox Energy Center located in the town of Kaukauna. Construction on that project has not commenced. However, in November 2002 the Commission issued an Order approving the Fox Energy Center CPCN application (docket 05-CE-115). The Fox Energy Center is rated at 510 MW with 250 MW of that capacity already under contract to Wisconsin Public Service Corporation. As for energy and capacity pricing, Calpine did not materially change terms in its June 20, 2003 proposal update, although it did allow for shorter contracting periods.

The Calpine proposal submitted to the PSC contains a sample power purchase agreement (PPA) with relevant economic and engineering terms and conditions. Such terms and conditions, due to their trade secret nature, have been filed confidentially at the PSC and are available only from Calpine after entering into an appropriate trade secret protection legal framework. Calpine believes its Fond du Lac Energy project and Fox Energy Center are superior in cost, fuel efficiency, and emissions to the ERGS coal plant facilities. Calpine believes it could begin construction on the projects as early as late 2003 with commercial operation in summer 2006. Calpine has indicated that later commercial operation dates are also available.

Staff's analysis of Calpine's proposal

The environmental effects of building and operating the Calpine Fond du Lac Energy Center were fully analyzed and described in a final EIS prepared by Commission staff for Calpine's original CPCN application. Two sites on the southeast side of Fond du Lac were proposed for the facility, one along River Road directly adjacent to Alliant's South Fond du Lac peaking generation plant and the other, about one-half mile east along Hickory Road directly across from a new Charter Steel industrial plant. The executive summary from the final EIS for the Calpine Fond du Lac Energy Center is attached as Appendix A-1.

The environmental effects of building and operating the Fox Energy Center were fully analyzed and described in a final EIS prepared by PSC and DNR staff. The executive summary from the final EIS for the Fox Energy Center is attached as Appendix A-2.

In this final EIS for the ERGS project, Commission staff has performed some initial EGEAS analysis of Calpine's proposal to provide 523 MW of combined-cycle capacity to WEPCO from the Fond du Lac Energy Project and 260 MW of combined-cycle capacity to WEPCO from the Fox Energy Center. That cost analysis is contained and explained more fully in the EGEAS modeling section of Chapter 4 below.

Lastly, as part of any project approval, the Commission will have to determine whether the process used by WEPCO for evaluation and selection of proposals to meet its electric needs has produced a cost effective, timely, and likely project for WEPCO ratepayers, with respect to all quantitative and qualitative considerations. Given the substantial cost and dollar magnitudes involved and the relatively few projects to choose from, this is an extremely important topic for the Commission to consider, especially because of the significant potential effects on the southeastern Wisconsin economy if too many coal units are approved or there are major cost overruns. The consequences of these errors are described later in this chapter.

EGEAS Sensitivities (Integrated Resource Alternative)

Both the company and Commission staff used the professionally-accepted EGEAS (Electric Generation Expansion Analysis System) model to compare alternatives to the ERGS facilities. EGEAS is a modular production-costing, generation-expansion software tool that is used to find least-cost generation system expansion plans by comparing all combinations of multiple generation options to meet forecasted system load. EGEAS inputs include forecasted energy and demand, the economic and engineering characteristics of existing and possible new generation units, fuel price forecasts, known or expected energy purchases or sales, desired reserve margin, and the forecasted cost of emission allowances.

Commission staff addressed the following scenarios when performing its EGEAS analyses: 1) Base Case; 2) DSM-EIA Load Growth; 3) High Gas Prices; 4) Low Gas Prices; 5) High Coal Prices; 6) Low Coal Prices; 7) Coal Capital Costs plus 10 percent (this scenario addresses the potential for cost overruns as described earlier in Chapter 2); 8) CO_2 Monetization; 9) Monetization of SO_2, Hg, and NO_x Emissions; 10) Capacity of the SCPC of 615 MW; and 11) Retirement of all Coal at 60 years. For each of these scenarios, Commission staff performed an EGEAS run assuming three different outcomes:

- Optimal operation (EGEAS picks the best combination of WEPCO generating options)[48]
- Optimal operation with a Calpine 523 MW combined-cycle unit by 2007
- Two SCPC units (2008 and 2009); no IGCC unit

These scenarios are denoted Optimal (w/o Calpine), Calpine, and ERGS-no IGCC in Table 4-4 below. Lastly, each of the scenarios was modeled assuming the continued existence of the current wind tax credit (escalated for inflation over time). In these runs, wind development potential was limited to that placed into the EGEAS model or "hard-wired" by WEPCO presumably to reflect its potential commitment to the renewable resource under its complete Power the Future plan. (WEPCO recently submitted an RFP for 200 MW of wind generation which the company includes in its model by 2005. The company then adds another 50 MW of wind in 2011. The company also adds more wind in later years, totaling 410 MW of additional wind by 2030.) As a sensitivity, an EGEAS analysis was conducted by placing no limit on wind development potential as discussed later.

Commission staff based its capital cost parameters on the Commission's decision in the Port Washington case (docket 05-CE-117). These assumptions were 12.7 percent return on equity, 6.0 percent cost of long-term debt, and a capital structure of 53 percent equity and 47 percent long-term debt. These financing assumptions are less costly than those sought by WEPCO, namely a 12.90 percent return on equity using 58 percent common equity in the capital structure.

[48] This distinction is necessary relative to the next one because WEPCO does not have the Calpine proposal to evaluate, as PSC staff did.

Commission staff's Base Case assumes the following inputs:

- updated forecast for peak demand and energy use provided by WEPCO
- base coal and gas prices as forecasted by WEPCO beginning at $1.38 MMBtu for coal and $6.57 MMBtu for natural gas in 2003. In 2007, these fuel prices are $1.52 MMBtu and $4.67 MMBtu respectively in the WEPCO base fuel price forecast.
- the approved Port Washington facilities (two 545 MW combined-cycle units with one installed in 2005 and the other in 2007 or 2008)
- retirement of Presque Isle units 1-4 and Oak Creek 5 and 6 at the end of 2012.
- retirement of other coal plants at age 60
- relicensing of Point Beach Nuclear Power Plant Units 1 and 2
- Wind Tax Credit at $18 per MWh for 2002 (and escalated for inflation)

The wind units have a capacity factor of 30.0 percent. Commission staff assumed that these wind units have a 20 percent credit to reserve margin, which means for every 100 MW only 20 MW are counted towards the utility's reserve margin.

As an alternative to WEPCO's higher forecast of demand and energy, Commission staff applied its estimated impact of DSM programs through 2011 and then applied EIA growth factors to the peak and energy forecasted at 2011 for the period through 2031 (see Chapter 3, Table 3-6 "Projected Growth in Energy Use and Peak Demand). Commission staff believes that WEPCO's revised forecast is not unreasonable but perhaps slightly optimistic. Therefore, it is important to identify the impact on the economics of the ERGS proposal assuming a lower forecast for peak and energy.

Commission staff used WEPCO's high and low forecasts for coal and gas for its price sensitivity runs. Commission staff also used a 10 percent cost overrun on new coal units as a sensitivity to reflect WEPCO's new pricing proposal made available in its May 2003 direct testimony. Finally, a Calpine proposal for 523 MW filed with the PSCW in February 2003 (and updated in June 2003) was modeled as a potential substitute for ERGS coal units. In June 2003, Calpine also submitted a proposal for 260 MW of combined-cycle capacity from its recently acquired Fox Energy Center which received a CPCN in November 2002. A sensitivity analysis of that proposal is also examined below.

Commision staff incorporated the retirement of Presque Isle units 1-4 and Oak Ceek 5 and 6 at the end of 2012 to reflect the tentative agreement WEPCO has with the US Environmental Protection Agency (US EPA) which is the result of a settlement for WEPCO's violation of Clean Air Act standards. Commission staff also has a sensitivity where all coal plants are assumed to be retired at age 60.

Commission staff moved the installation of the first SCPC unit from 2007 to 2008 for the ERGS without IGCC proposal since the lease calls for the first unit to come on-line in May 2008.

EGEAS results - with 410 MW of wind by 2030

Table 4-4 shows that, for the DSM-EIA Load Growth and the High Gas Prices scenarios, the EGEAS run with Calpine's 523 MW combined-cycle unit forced to be taken in either 2006 or 2007 is not least cost when compared with the EGEAS run with WEPCO-only generation incorporated. For the remaining cases shown in Table 4-4, the EGEAS model with the 523 MW Calpine Fond du Lac unit is immaterially different from the EGEAS run with WEPCO-only generation. However, in all of the scenarios in Table 4-4, the EGEAS run that includes the 523 MW Calpine unit is materially more economic than the ERGS without IGCC proposal from WEPCO. In the base run for instance, the expansion plan with the 523 MW Calpine Fond du Lac project is $95.6 million lower cost on a present value basis than ERGS without IGCC.

As is shown in Appendix A, Summary of EGEAS Expansion Plans, the presence of Calpine's 523 MW unit pushes the first coal plant out to at least 2011, except for the CO_2 monetization scenario where the Calpine and Optimal runs without Calpine push coal out to 2025. For the EGEAS runs with WEPCO-only generation, coal is pushed back to 2009, except for the DSM-EIA Load Growth scenario where the first unit is pushed out to 2012, the Coal Capital Costs plus 10 percent scenario where the first coal unit is selected in 2011 and the CO_2 monetization scenario.

Table 4-4 Cost comparisons of EGEAS modeling results with wind limited to 410 MW

	EGEAS Model Results NPV ($000,000)			Differences from Optimal		
Scenario	Optimal w/o Calpine	Calpine	ERGS - no IGCC	Optimal w/o Calpine	Calpine	ERGS - no IGCC
Staff Base Case	19,073.7	19,080.7	19,176.3	0.0	7.0	102.6
DSM- EIA Load Growth	16,914.8	16,979.9	17,144.2	0.0	65.1	229.4
High Gas Prices	19,233.0	19,261.8	19,334.9	0.0	28.8	101.9
Low Gas Prices	18,690.1	18,686.8	18,821.1	0.0	-3.3	131.0
High Coal Prices	19,353.3	19,354.4	19,458.5	0.0	1.1	105.2
Low Coal Prices	18,823.0	18,836.7	18,921.9	0.0	13.7	98.9
Coal Cap. Costs + 10%	19,485.6	19,475.0	19,625.2	0.0	-10.6	139.6
Staff Base Case with CO_2 Monetization	27,009.9	27,017.2	27,356.6	0.0	7.3	346.7
Hg, SO_2 and NO_X monitization	19,506.3	19,504.4	19,610.3	0.0	-1.9	104.0
Coal Capacity at 615 MW	19,106.2	19,106.6	19,261.4	0.0	0.4	155.2
Retire Coal at 60 Years	18,722.8	18,736.3	18,825.2	0.0	13.5	102.4

Note: Optimal without Calpine is equivalent to WEPCO-only generation. This distinction is necessary, related to the Calpine run because WEPCO does not have the Calpine proposal to evaluate, as PSC staff did.

Figures 4-3, 4-4, and 4-5 depict the Base Case expansion plans for the period 2004 to 2014 under the Optimal without Calpine, Calpine, and ERGS w/o IGCC approaches. For reference sake, the Optimal w/o Calpine expansion plan in Figure 4-3 is $7 million less expensive on a present value basis than the expansion plan with Calpine proposals in Figure 4-4. As indicated, this difference is statistically immaterial. On the other hand, the Calpine expansion plan in Figure 4-4 is $95.6 million less expensive than the WEPCO proposed expansion plan w/o the IGCC unit which is depicted in Figure 4-5. Examination of the following figures shows that coal plants are generally part of a least cost EGEAS expansion plan for WEPCO. However, the optimal timing appears to be for the period 2009 and 2011, which is about two to three years later than the operational date sought by WEPCO in its CPCN application.

Figure 4-3 Optimal expansion plan without any Calpine units

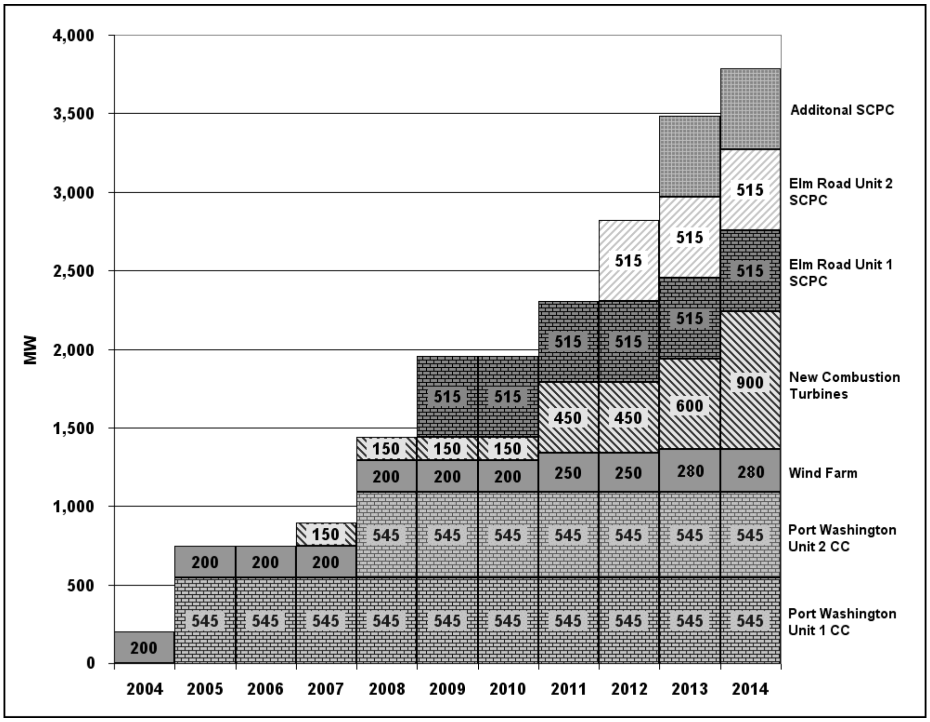


Figure 4-4 Expansion plan with Calpine proposal

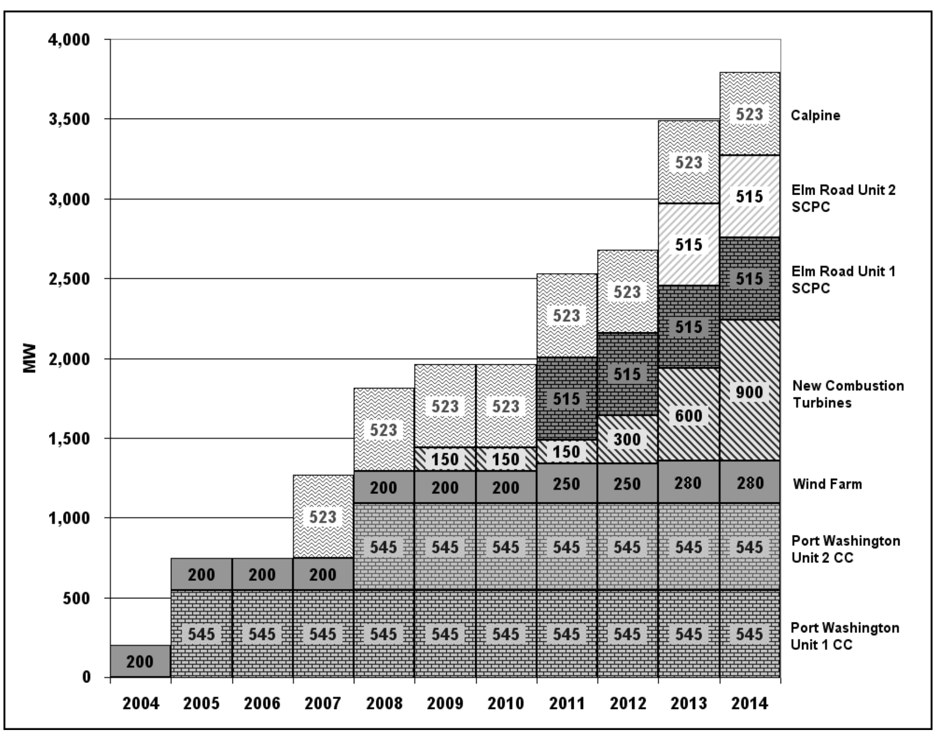
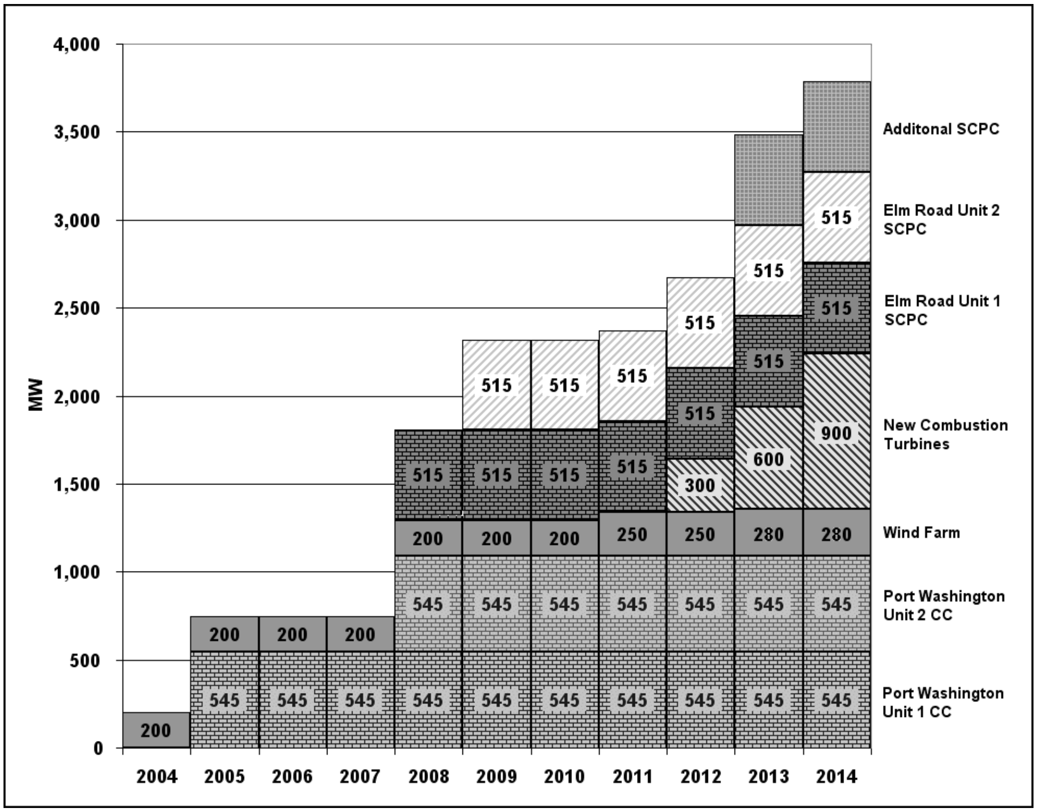


Figure 4-5 Expansion plan for WEPCO's ERGS without IGCC



EGEAS Results- with No Limit on Wind

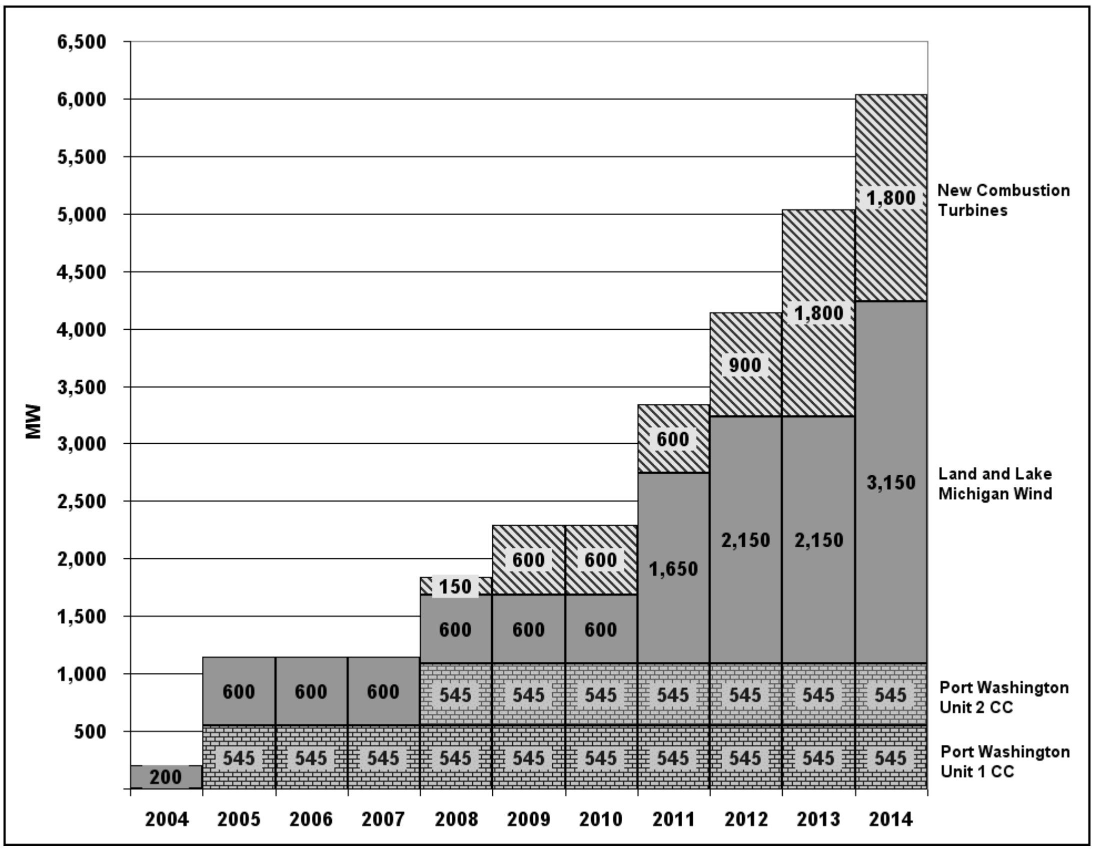
Commission staff also ran scenarios in EGEAS where wind was allowed to be picked freely by the EGEAS model. The results are shown in Table 4-5. Commission staff used two sources of wind—the first was based on the bids that WEPCO received from its RFP (request for proposal) and the second was wind assumed to come from offshore in Lake Michigan. For the Lake Michigan wind, a 35 percent capacity factor was assumed (as compared to the 30 percent assumed by the company for its wind units). Both sources of wind were assumed to make a 20 percent contribution to the capacity reserve.

Commission staff looked at two scenarios—one with the wind tax credit continuing through the foreseeable future and the other with no wind tax credit. In both cases, the Calpine proposal was significantly less expensive than the ERGS w/o IGCC proposal. For the continuing wind tax credit scenario, the Optimal run was, however, less expensive than the Calpine run since the presence of an additional 523 MW of combined-cycle reduces the amount of wind and wind production tax credit (PTC) that the EGEAS model can select. In the "no limit wind" run, the EGEAS model selects up to 2,500 MW of Lake Michigan wind by 2014. This is in addition to 400 MW of new land-based wind placed into service in 2005. In neither the Optimal nor Calpine runs is any coal picked for the wind tax credit continuation scenario. Figure 4-6 displays the 2004 to 2014 expansion plan when there is no limit on wind generation development.

Table 4-5 EGEAS model results under unlimited wind scenario

	EGEAS Model Results NPV ($000,000)			Differences from Optimal		
No Limit on Wind Scenario	**Optimal w/o Calpine**	**Calpine**	**ERGS - no IGCC**	**Optimal w/o Calpine**	**Calpine**	**ERGS - no IGCC**
No limit on Wind with the Wind Tax Credit	14,794.8	14,945.9	15,547.1	0.0	151.1	752.3
No limit on Wind; No wind Tax Credit	18,020.8	17,899.7	18,128.6	0.0	-121.1	107.8

Figure 4-6 Expansion plan with no limit on wind development and with continuing PTC



There are two concerns Commission staff has with the unlimited wind capacity and the continuing wind tax credit scenario. First, EGEAS picks so much wind capacity that baseload units have drastically reduced capacity factors in later years. Second, Commission staff does not believe that the federal government would be willing to pay $18 per MWh (2002$) for the volume of wind of 11,000 MW by 2023 selected by EGEAS under this scenario.

For the no wind tax credit scenario, the Calpine run is the most economic. For the Calpine run, the first coal unit is pushed out to 2011, whereas the Optimal without Calpine run picks its first coal unit in 2009. The Calpine proposal is significantly less expensive than the ERGS w/o IGCC proposal. With no wind tax credit, no new wind is picked by EGEAS until 2017.

Other EGEAS Analyses

Commission staff also analyzed a June 2003 proposal from Calpine for 260 MW of combined-cycle capacity from its Fox Energy Center using Commission staff's Base Case assumptions. The Fox Energy proposal using only 260 MW in 2007 was more expensive than the Calpine Fond du Lac proposal using 523 MW by $12.4 million. (See Appendix A, Summary of EGEAS Expansion Plans) Commission staff did not run the EGEAS model with capacity available from both Calpine projects simultaneously due to limited time, but may explore that possibility in time for the technical hearing.

Commission staff made an EGEAS run with the IGCC unit included in the model for the Base Case scenario. The ERGS proposal with the IGCC was more expensive than the ERGS proposal without the IGCC by $247.1 million.

Commission staff made an EGEAS run assuming no coal nor biomass, and wind limited to that hardwired by WEPCO. The cost of that plan was less economic than the Optimal plan by $1,937.8 million. When Commission staff allowed EGEAS to pick up to 1,500 MW of biomass, the resulting expansion plan was more expensive than the Optimal plan by $1,405 million. These latter sensitivities indicate that a mixture of properly timed gas- and coal-fired units would result in the lowest overall cost expansion plan for WEPCO.

EGEAS summary

10. The IGCC unit, which is the third unit in the ERGS proposal, is not cost-effective.
11. The proposed timing of the SCPC units in 2007 and 2009, as WEPCO has proposed, is not least cost. This scenario is generally more than $100 million more expensive on a present value basis. Timing appears to be about two to three years premature.
12. The Calpine 523 MW CC proposal in Fond du Lac using natural gas is lower cost than the ERGS - w/o IGCC proposal. However, the Calpine proposal would not need to be put in-service until 2007. Selecting the Calpine proposal does not mean that coal plants would not be needed. Several scenarios suggest that a coal plant would not be needed until 2011, if not later, if the Calpine proposal is selected.
13. CO_2 monetization, as well as other emissions monetization scenarios, favors picking the Calpine proposal versus ERGS w/o IGCC.
14. If the coal plants were to have cost overruns of 10 percent, then the Optimal expansion plan does not select a coal plant until 2011.
15. Should lower demand and energy growth occur due to increased energy efficiency efforts and lower overall use of electricity than depicted by WEPCO in its base demand and energy forecast, then the earliest a new coal facility would be needed is 2012.
16. ERGS w/o IGCC could be made competitive with the Calpine Fond du Lac proposal by the Commission choosing an overall finanacing plan that would cost ratepayers between $50 million and $100 million less on a present value basis.

17. Substantial Lake Michigan wind development exceeding 2,500 MW by 2014 and 11,000 MW by 2023 would be effective in meeting demand and energy growth for WEPCO, but it would require a substantial federal transfer via a permanent wind tax creit of $18 MWh. If the federal government were to not renew the wind tax credit presently set to expire in 2004, then no new wind would be selected by EGEAS until 2017.
18. An expansion plan over the next 30 years relying exclusively on natural gas would cost ratepayers $1.9 billion more than a balanced plan using optimally timed gas- and coal-fired electric generation, as well as some wind generation development.

There are important caveats in interpreting and understanding the above comments. First, Commission staff has used a strict materiality threshold of $10 million in interpreting the EGEAS model results. This means that Commission staff believes that expansion plan total costs that differ by more than $10 million are considered significant. Due to modeling complexity, the number and type of input assumptions, as well as the long-term nature of the EGEAS expansion plans, different parties may want to use other materiality thresholds. For instance, the Commission used a materiality threshold of $50 million during the Port Washington CPCN case. Using a $50 million materiality threshold still results in selecting Calpine proposal over the ERGS w/o IGCC proposal.

Another important caveat is that the Commission can choose a financing package other than the one proposed by WEPCO for ERGS and modeled here. The Commission could fashion a financing package for ERGS that would lower present value costs to ratepayers. For instance, in Chapter 3, rate-based financing rather than the lease approach could be used to lower ratepayer costs. Alternatively the Commission could still use a leasing approach but with different financial parameters.

It should also be noted that the above quantitative results only focus on parameters that can be directly modeled in EGEAS. The following sections adjust the EGEAS results for the ratepayer impact associated with mitigation payments under the WEPCO-city of Oak Creek agreement as well as the different transmission system upgrade costs associated with the various generation expansion plans.

Lastly, these results focus on quantitative effects. The Commission will need to consider the qualitative environmental and economic risks associated with the use of different fuels as discussed throughout this final EIS.

Effect on EGEAS results due to the potential for adverse credit quality effects on WEPCO's capital structure arising from the Facility Lease or a Purchase Power Agreement

When a long-term facility lease or purchase power agreement is signed, credit rating agencies can downgrade a utility's credit rating due to the debt-like quality of such agreements. This is especially the case if the lease or signed purchase power agreement constitutes a capital lease under Financial Accounting Standard Board (FASB) standards. Essentially, the signing of leases and PPAs with capital lease attributes and the attendant paying of rent or capacity payments looks much like a stream of continuing finance payments usually associated with long-term debt. This can reduce the utility's ability to obtain new financing and can raise borrowing costs as well. Any such increase in borrowing costs due to signed PPAs or leases needs to be factored into any generation cost analysis, including the quantitative EGEAS analysis reported above.

In this final EIS there has been no need to make quantitative adjustments associated with potential harm to the utility's credit rating. First, Calpine has proposed contract lengths in its proposal that make it less likely that a signed PPA for either the Fond du Lac Energy project or Fox Energy Center would constitute a capital lease under FASB standards. For instance, Calpine has not bid its proposals using a 25-year or longer term that would likely trigger capital lease accounting. Second, in the Port Washington construction case (docket 05-CE-117), WEPCO suggested and the Commission accepted the utility's commitment to treat all leases as operating leases for ratemaking purposes, and not as capital leases. Furthermore, WEPCO committed to a hold harmless provision with respect to debt costs if a transfer or assignment broadly defined of the leases or the Port Washington facility to a non-Wisconsin Energy Corporation company causes a national rating agency to downgrade the utility's debt rating or causes the utility to issue new equity to prevent such a downgrade, citing the lease as the reason. The Commission approved such terms in docket 05-AE-109. Similar conditions are expected in this ERGS docket. Finally, the facility lease itself contains a provision not allowing any such transfer or assignment broadly defined to occur for the first seven years after commercial operation of the ERGS. For these reasons, the EGEAS results have not been adjusted since the potential for credit quality degradation has been significantly reduced. Should underlying financing facts change with respect to either the ERGS or the Calpine proposals, a reexamination of this issue would be warranted.

Effect on EGEAS Results due to the WEPCO and city of Oak Creek Agreement

On March 25, 2003 the city of Oak Creek and WEPCO entered into an agreement by which WEPCO would, among several conditions, annually reimburse the city of Oak Creek $2.25 million after the start-up of the second SCPC plant that is part of the ERGS. This has not been modeled in the EGEAS quantitative results above, but the EGEAS results do need to be corrected for the long-term cost effect of the WEPCO-Oak Creek agreement. Specifically, the above EGEAS present value cost effects for the ERGS should be increased by $23.2 million. This $23.2 million is the 30 year present value of a stream of $2.25 million annual mitigation payments using a discount rate of 8.97 percent in an ordinary annuity formula. A 30-year period is used here because that is the facility lease's initial term.

Effect on EGEAS results due to necessary transmission system improvements

A proper cost analysis requires the inclusion of both generation and transmission costs. The EGEAS present value results depicted above only factor in electric generation capacity and energy costs. To these EGEAS generation costs, necessary transmission system improvement costs must be added in order to provide the overall generation and transmission impact to ratepayers.

Elsewhere in this FEIS it was indicated that the transmission system improvement costs associated with ERGS are $266 million. Without the third phase or IGCC component, the corresponding value is $164 million for the 1,230 MW of supercritical pulverized coal capacity. This latter transmission cost is used in the following discussion due to EGEAS modeling results showing that the IGCC phase is non-economic. It is important to note that this $164 million value may be overstated due to the fact that the July 2002 ATC study underlying it included generation projects that are unlikely to be constructed such as the 1,100 MW PG&E Badger Generating Station. Moreover, the July 2002 ATC study did not factor in the retirement of 500 MW of generating capacity associated with Oak Creek units 5 and 6 that now appears likely due to the EPA-WEPCO emissions agreement. How these elements would affect the $164 million estimate is unclear without a formal study. ATC is presently conducting such an analysis, but official results are not available at the writing of this FEIS. Preliminary discussion between Commission staff and ATC staff suggests the $164 million may be decreased to $80 to $100 million.

As for the Calpine 523 MW Fond du Lac Energy project and the 510 MW Fox Energy Center, the estimated combined transmission cost is $40 million for 1,033 MW of gas-fired capacity. In order to compare this value which is based on 1,033 MWs with the cost of the ERGS project without the IGCC unit which is based on 1,230 MWs of capacity requires some normalization. For this reason, the $40 million for the combined Calpine projects is escalated by the simple ratio of 1,230/1,033 to arrive at a $48 million value for the cost of necessary transmission improvements. This represents a preliminary and simplistic analysis requiring further advanced study.

Nonetheless, the discussion here indicates that the Calpine projects may enjoy between a $30 and $120 million construction cost advantage with respect to necessary transmission improvements. The 2003 present value of such construction amounts if the transmission assets were put in service in 2008 is between $28 million and $111 million using a 13.70 percent return on equity and a 40-year depreciation period. This $28 million to $111 million present value range would correspondingly increase the Calpine projects' advantage in the EGEAS generation results if both a generation and transmission cost perspective were used. Such a value should be used cautiously as the Calpine projects have not had official ATC load flow or "source and sink" transmission impact studies conducted in which the delivery point is the WEPCO system.

Potential adverse economic development effects caused by constructing a generation expansion plan that is improper or too expensive

In this EIS, there is much discussion about the optimal, cost-effective generation expansion plan for WEPCO. In particular, there are results of various EGEAS computer model simulations. The point of the EGEAS simulations is to find the generation expansion plan that accommodates WEPCO's system needs in a cost-effective fashion. Selecting an expansion plan that does not accommodate WEPCO's system needs would have an adverse economic development impact. First, in the situation where insufficient electric power and energy are available due to an improper generation expansion plan, the electric system becomes unreliable. This leads to general business uncertainty, increased operational costs for business, and scheduling and production inflexibility.

Such factors would impose a tremendous economic cost on the economy of southeastern Wisconsin which would most likely take the form of business relocation or expansion outside of the area and consumers having less money to spend. Estimating the actual economic loss from insufficient electric power and energy is problematical, but the loss would likely be substantial in dollar and qualitative terms.

The second potential adverse impact comes from constructing an optimal expansion plan that is too expensive, due to either cost overruns or poor project selection. Estimating the loss to the southeastern Wisconsin economy is somewhat easier in this situation if the extra expense for electricity is viewed akin to a sales tax increase.

A recent study of the impact of tax increases on the Wisconsin economy shows that each $10 million increase in sales taxes has the potential to eliminate around 350 jobs.[49] Elsewhere in this EIS, it is reported that the annual lease payment from WEPCO to WE Power would be $111.25 million for each of the pulverized coal units. This means that a 10 percent construction cost overrun would make the annual lease payment cost about $11 million more than without the overrun. This ten percent overrun estimate is used because in its June 2003 testimony WEPCO has capped the cost overrun potential under the facility lease to no more than ten percent. If viewed as an unnecessary $11 million tax increase, such a 10 percent cost overrun could hurt the southeastern Wisconsin economy by about 385 jobs per year per unit.[50]

Lastly, there would be an impact if more coal units are approved than are actually needed. If WEPCO were to pay WE Power for a coal plant that was constructed but not needed, WEPCO under the facility lease would have to pay an annual rent of $111.25 million. Using the job-loss-to-sales-tax-increase estimate from above would translate into a loss of about 3,900 jobs per year per unit. For this reason, the Commission may want to consider a phased approach to the construction of the ERGS facilities, requiring the second or third units be constructed only after another examination of electric demand needs. In the case of an overbuilding scenario, the job loss impact would diminish slowly through time as electricity demand grew, eventually requiring the excess capacity to be used.

Nuclear Power as an Alternative

Currently, construction of new nuclear power plants is prohibited by Wis. Stat. § 196.493. However, this prohibition will cease once Yucca Mountain, or a similar geologic repository, becomes operational.

In July 2002, the U.S. Senate approved the development of Yucca Mountain as a long-term geologic repository. According to the Office of Civilian Radioactive Waste Management web site, the US Department of Energy (DOE) is "currently in the process of preparing an application to obtain the Nuclear Regulatory Commission license to proceed with construction of the repository." The 2004 budget proposed by DOE anticipates that Yucca Mountain will be operational by 2010.

During the scoping process, members of the public suggested that the Commission examine the possibility of replacing the proposed ERGS coal units with nuclear power plants. Evaluating the option of a nuclear power plants as an alternative to the ERGS proposal, requires the following assumptions:

1. Wis. Stat. § 196.493 remains unchanged.
2. Yucca Mountain begins operation in 2010.
3. The Nuclear Regulatory Commission's (NRC) early site approval process is not precluded by Wis. Stat. § 196.493.
4. WEPCO could complete the early site approval process by 2010.
5. The Westinghouse AP600 nuclear facility is used in EGEAS modeling. The AP600 is similar in size to the proposed ERGS coal units and its design has been approved by the NRC.
6. A new nuclear unit could be constructed and placed in operation within 36 months, once site approval is obtained. This would allow the EGEAS model to choose a new nuclear unit beginning in 2013.

[49] "Raising Taxes in Wisconsin—Measuring the Full Costs," Wisconsin Policy Research Institute Report, Volume 16, Number 1, January 2003. This study shows that 55,514 jobs would be lost from a $1.6 billion sales tax increase, basically a 350 jobs to $10 million ratio.
[50] Calculated as [$21 million / $10 million] times 350 = 735

Commission staff ran four different scenarios in EGEAS where the model could choose new nuclear generation. The four scenarios included two different capital costs,[51] including contingencies, each run with a "monetize CO_2" (which adds a cost for greenhouse gas emissions) and a "no monetization of CO_2" sensitivity.

WEPCO supplied its estimate of reasonable costs associated with the construction of a new nuclear power plant. It estimated a capital cost of $2,116 per kilowatt (kW). This is very close to the number used by DOE and found in the assumptions to Energy Information Administration's (EIA) Energy Outlook 2002, which is $2,144 per kW for an advanced nuclear generating unit. Commission staff used WEPCO's $2,116 per kW as one estimate of overnight costs in its EGEAS modeling.

Based on information available in Public Utilities Fortnightly, a capital cost (without contingencies) for the AP600 would be $1,500 per kW. Using the same percentage for contingencies as found in the assumptions to EIA's Energy Outlook 2002, the overnight cost for the AP600 with contingencies would be $1,815 per kW. This was the other overnight cost utilized by Commission staff in its EGEAS modeling.

If a capital cost of $2,116 per kW is used, the EGEAS model does not pick a nuclear unit to meet new generation needs, regardless of whether CO_2 is monetized or not. If the lower estimate of overnight costs ($1,815 per kW) is used and CO_2 is monetized, the EGEAS model picks one new nuclear unit in 2013 to meet new generation needs. Without CO_2 monetization, no new nuclear units are chosen.

The assumptions used in this analysis of nuclear plants do include significant uncertainties. There is uncertainty associated with which advanced reactor design WEPCO would actually choose. This has an impact on the overnight costs used in the EGEAS model. The fact that no new orders for nuclear plants have been placed in this county since the late 1970s also adds uncertainty in the overnight cost associated with building a new nuclear unit and the length of time from start of construction to the point when the plant is brought on line.

The largest uncertainties lie in the first two assumptions above. The commercial operation date for Yucca Mountain is not certain. For Yucca Mountain to become operational, NRC must approve the construction of the repository. Any delay in the projected 2010 in-service date for Yucca Mountain directly impacts when a new nuclear unit can be allowed to be chosen by the EGEAS model. The continued applicability of Wis. Stat. § 196.493 is also an uncertainty, but because this statute has no sunset date it is reasonable to assume that it will remain in effect, unchanged.

Given this lack of certainty associated with several important assumptions about a nuclear option, it does not appear that new nuclear generation is a viable alternative to the ERGS proposal at this time.

[51] In the Energy Information Administration's Energy Outlook 2002, these costs are referred to as "overnight" costs.